

ACCOUNTING AND TAX ASPECTS OF OIL AND GAS JOINT VENTURES

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INTRODUCTION

It is often desirable in the oil and gas production industry for two or more persons to share the financial risks of a venture. Frequently an investor may have the funds and the desire to participate in an oil venture, but may lack either the "know-how" or the time to manage the venture. In such situations, it is necessary to establish some form of organization whereby an association of two or more individuals or companies can carry out the operation.

The three most common forms of business associations used in the oil and gas production industry are corporations, co-ownership arrangements (joint ventures), and partnerships. Financing of oil and gas operations through formation of a syndicate has gained increasing acceptance in recent years. Some syndicates may be operated through a joint venture arrangement while others are operated through limited partnerships.

The purpose of this article is to set forth some of the important tax considerations of the corporate, joint venture, partnership, and syndicate forms of operation and to suggest accounting and record keeping techniques that will be useful to the oil investor and operator.

CORPORATIONS

The usual advantages and disadvantages of the corporation as applied to all commercial activities are equally applicable to the oil and gas production industry. For instance, the corporation has the advantage of providing limited liability to the owners or shareholders. On the other hand, except for "electing small business corporations,"¹ the corporation also has the disadvantage of double taxation, *i.e.*, the corporation itself is taxed on its income and the owners are taxed on dividend distributions.

The corporation is usually the most efficient form of organiza-

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¹ Int. Rev. Code of 1954, § 1371(a); Treas. Reg. § 1.1371-2 (1959).

tion for operating an enterprise with a large number of owners distinct and apart from the management. Where the capital requirements of an enterprise are of such magnitude as to require widespread ownership it is usually impractical to consider any form other than the corporate form. Other factors also dictate the adoption of the corporate form. It is fully recognized that sound decisions regarding the form of organization can be made only in the light of particular circumstances involved. However, in the case of the small operator or the individual investor in the specialized industry of oil and gas production it is usually more advantageous, strictly from an income tax standpoint, to own mineral properties producing depletable income at the individual rather than at the corporate level. There are some rather distinct disadvantages to the corporate form of organization for such persons because of the special tax problems with which they are confronted.

Those disadvantages arise because the corporation is taxed as an entity separate and distinct from its owners. As an entity the corporation takes title to the assets of the enterprise, computes its taxable income or losses as its own, and pays corporate income tax on its taxable profits. Except in the case of "electing small business corporations,"² the individual owner or shareholder of a corporation does not, for income tax purposes, recognize income or losses as incurred by the corporation; he recognizes corporate income only when he receives a distribution from the company in which he owns shares.³ Generally, the shareholder cannot recognize corporate losses on his personal tax return except indirectly by disposing of his stock. A loss on the sale of stock would represent a capital loss which is not fully deductible from ordinary income.⁴

² *Ibid.*

³ Int. Rev. Code of 1954, § 301.

⁴ Int. Rev. Code of 1954, § 1211(b). Taxpayers, other than corporations, are allowed to deduct losses on the sale or exchange of capital assets to the extent of the capital gains from sales or exchanges of capital assets plus \$1,000 or taxable income, whichever is smaller. Where the stock is that of a "small business corporation" the loss is limited to \$25,000 (\$50,000 for husband and wife filing a joint return) and the loss is classified as an ordinary loss. Int. Rev. Code of 1954, § 1244.

The disadvantages of the corporate form are illustrated as follows: (1) Assuming an individual is in a high income tax bracket, the attractiveness of the risk of making an investment in an oil venture is the relatively low dollar cost to him of development expenditures. The low cost is made possible because the investor can usually take the intangible drilling and development costs of the venture as an immediate deduction against income from other sources. If such costs are incurred by a corporation rather than by the investor directly, they would be deductible by the corporation and not by the investor individually. (2) Generally distributions from

As a result of amendments in 1958 to the Internal Revenue Code, certain qualifying corporations (small business corporations) may, with the consent of all shareholders, elect to be treated substantially as a partnership for federal income tax purposes. A "small business corporation" is defined as a domestic corporation which is not a member of an affiliated group and which does *not*:

- (1) have more than ten shareholders;
- (2) have as a shareholder a person (other than an estate) who is not an individual;
- (3) have a nonresident alien as a shareholder; and
- (4) have more than one class of stock.⁵

For the years in which a valid election is in effect, the "small business corporation" is not taxed. The shareholders include the corporation's taxable income ratably in their individual taxable

earnings and profits of a corporation are taxable to the recipient as ordinary income. Some deductions taken by a corporation in arriving at its taxable income must be restored to earnings and profits. The prime example bearing most directly on the oil and gas production industry relates to the deduction for percentage depletion. Specifically, percentage depletion (in excess of cost depletion) allowed as a deduction in arriving at taxable income does not represent a reduction in earnings and profits. Treas. Reg. § 1.312-6(c)(1) (1955). While previously allowed percentage depletion reduces the leasehold basis for purposes of computing allowable cost depletion for the current year, cost depletion for earnings and profits purposes is computed by reducing leasehold basis for all years for cost depletion *only* even though percentage depletion in prior years exceeded cost depletion. Assume that an oil company has no accumulated earnings and profits from prior years and that taxable income for the current year is zero. Also assume that the deductions taken to arrive at the current year's taxable income includes percentage depletion that is \$50,000 in excess of cost depletion. A distribution of \$40,000 is made to the shareholders. It would appear on the surface that the distribution would represent a return of capital to the shareholders—not so; the distribution would normally represent a dividend taxable as ordinary income as follows:

Accumulated earnings and profits from prior years		\$ —
Taxable income for current year	\$ —	
Add back percentage depletion allowed in excess of cost depletion	50,000	50,000
	<hr/>	<hr/>
Earnings and profits available for dividends		50,000
Less dividend paid—ordinary taxable income to recipients		40,000
		<hr/>
Remaining accumulated earnings and profits to be carried forward		<u>\$10,000</u>

⁵ Int. Rev. Code of 1954, § 1371(a). It should be noted that the benefits of a "small business corporation" are not available if 80% of the corporation's gross receipts for the taxable year are from sources outside the United States. Hence,

income. An operating loss of the corporation is also passed through ratably to the shareholders.

This article will not deal with the elaborate provisions in the Code relating to adjustment of stock basis for undistributed income reported by the shareholder, for losses passed through to the shareholder, or for subsequent tax-free distributions of undistributed income taxed earlier to the shareholder. All of those provisions and a number of other matters would require careful consideration in the light of the particular circumstances and facts applicable to a corporation and its shareholders contemplating the election. However, in considering the election for an oil or gas producing company, it is important to recognize that earnings and profits which represent the source of taxable distributions are reduced by the corporation's taxable income reported individually by each shareholder. The excess of percentage depletion over cost depletion must, as explained heretofore, be added back to taxable income in arriving at earnings and profits available for dividend distribution. Thus, assuming the corporation was an "electing small business corporation," enjoying the benefits of percentage depletion, distributions from taxable income could be made without further incidence of tax to the shareholders but distributions from earnings and profits represented by the excess of percentage depletion over cost depletion would be taxable as a dividend to the shareholders.⁶

Assume that a producing oil and gas corporation had made the election to be taxed as a "small business corporation" from its inception and that its taxable income for the first year of operation was 50,000 dollars as follows:

Income before depletion		\$ 100,000
Depletion:		
Cost depletion	\$ 10,000	
Excess of percentage depletion over cost depletion	40,000	50,000
Taxable income		<u>\$ 50,000</u>

Each shareholder would report his ratable share of the above 50,000 dollars taxable income in his individual income tax return. In that situation the earnings and profits of the corporation would be as follows:

the advantages of the "small business corporation" will not be available in the case of many corporations involved in foreign operations. Int. Rev. Code of 1954, § 1372(e) (4).

⁶ Treas. Reg. § 1.1377-2(b) (1959).

Taxable income	\$ 50,000
Excess of percentage depletion over cost depletion	40,000
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	90,000
Less—Taxable income reported by each shareholder	50,000
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Earnings and profits available for taxable dividend	<u>\$ 40,000</u>

Thus, if a distribution of 90,000 dollars was made to the shareholders at this point, 50,000 dollars would not be subject to further tax upon receipt by the shareholders, but 40,000 dollars would represent ordinary dividend income to the shareholders.

CO-OWNERSHIP ARRANGEMENTS

"Joint venture" is the term commonly applied in the oil and gas industry to co-ownership arrangements. The Internal Revenue Code provides that "the term 'partnership' includes a syndicate, group, pool, joint venture, or other unincorporated organization through or by means of which any business, financial operation, or venture is carried on, and which is not . . . a corporation or a trust or estate."⁷ Generally a joint venture for the development and operation of an oil property would fall within that definition of a partnership. However, the Code also provides that if an unincorporated organization is availed of "for the joint production, extraction or use of property, but not for the purpose of selling services or property produced or extracted" such an organization may, at the election of all of the members of the organization, be excluded from the partnership provisions of the Code.⁸ The eligibility for this election is further predicated on the presumption that the income of the members of the organization may be adequately determined without the computation of partnership taxable income.⁹

Although this article will not deal with the many important aspects to be considered in making an effective election,¹⁰ participants in a joint venture should consider carefully the partnership provisions and the advisability of operating as a partnership or electing to be excluded from partnership classification. Because of the ramifications of the partnership rules, participants in oil and

⁷ Int. Rev. Code of 1954, § 761(a) ; Treas. Reg. § 1.761-1(a) (1956).

⁸ *Ibid.*

⁹ Treas. Reg. § 1.761-1(a) (2) (1956).

¹⁰ See Treas. Reg. § 1.761-1(a) (2) (iii) (iv) (1956) for the election requirements.

gas joint ventures have generally preferred to be excluded from these provisions of the Code and therefore have perfected the necessary election. However, in circumstances later to be discussed the partnership provisions may be used to advantage.

From an income tax standpoint, if the foregoing election has been effectively made, a properly constituted joint venture is not an entity separate and distinct from its co-owners. This is an important characteristic distinguishing a joint venture from a corporation or a partnership. Notwithstanding that characteristic, a joint venture does provide a form of organization whereby two or more persons (or corporations) may pool their resources for a business purpose.

The joint venture is a contractual arrangement among the participants. One of the participants is designated as the operator in the joint venture agreement. The agreement should set forth the procedures for accounting for the participants and the sharing of expenditures among the participants and provide for the distribution of production from the property and the interests of the participants in the production.

Generally, the operating agreement among the participants will include detailed provisions covering the accounting procedures to be followed. A standard form frequently used for this purpose is COPAS-1962, Accounting Procedure (Joint Operations), which was devised by The Council of Petroleum Accountants Societies of North America.

The operating agreement should specifically provide the participants with the right to make periodic audits of the records of the operator pertaining to the joint venture since most of the detailed records such as invoices and evidence of invoice payments are in the possession of the operator. Moreover, many facets of joint ventures, such as the allocation of overhead items to various joint ventures and the determination of prices to be paid to the operator for equipment purchased from him by the joint venture make audits desirable. The operator as well as the other participants usually welcome joint venture audits since such audits are for the protection and benefit of all of the participants. These audits are frequently performed by independent public accounting firms.

The standard provision for audits contained in the COPAS form is as follows:

A Non-Operator, upon notice in writing to Operator and all other Non-Operators, shall have the right to audit Operator's accounts and records relating to the accounting hereunder for any calendar year within the twenty-four (24) month period follow-

ing the end of such calendar year. . . . Where there are two or more Non-Operators, the Non-Operators shall make every reasonable effort to conduct joint or simultaneous audits in a manner which will result in a minimum of inconvenience to the Operator.

The operator's role is to develop and operate the properties for the benefit of all participants. Title to the properties is not conveyed to the joint venture, but each participant retains title to his undivided interest in the properties.

The typical joint venture provides that each owner will bear his proportionate share of the cost of developing and operating the property and each owner will be entitled to his proportionate share of the oil, gas, or other minerals produced from the property. Each participant must make his own elections as to handling particular items for tax purposes. For example, one party may elect to use the declining balance method of computing depreciation on his share of additions to depreciable property, and another may use the unit of production method on his share.¹¹

Under the joint venture arrangement, each participant reserves the right to take in kind and to dispose of his share of the production from the property for his own account. As a practical matter, the operator is usually given the authority as agent to market the production for the account of all participants. Furthermore, the operator's authority should be limited in the joint venture agreement in such a manner that he is not permitted to enter into any sales contract for a period longer than is required by the minimum needs of the oil and gas industry and in no event for a period longer than one year.

In drawing the joint venture agreement and in the actual operation of the venture, care must be exercised to avoid classification of the joint venture as an association taxable as a corporation.¹² From an income tax standpoint, associations of persons, even though not in formal corporate form, may so closely resemble a corporation as to become taxable as one. If a joint venture should

¹¹ Assume for purposes of illustration that *A* is designated as the operator of a joint venture, owning $\frac{5}{8}$ working interest, *B* owning $\frac{2}{8}$, and *C* $\frac{1}{8}$ royalty interest. Customarily, *A* would pay all costs of developing and operating the property and each month would bill *B* for $\frac{2}{7}$ of such costs. *A* would distribute $\frac{5}{7}$ of the total costs to the appropriate fixed asset and expense and other accounts in his own accounting records and would set up an account receivable from *B* for $\frac{2}{7}$ of all costs and would bill *B*, usually each month, for $\frac{2}{7}$ of such costs. The billing should be in sufficient detail to permit *B* to properly account for his share of the costs. *B* in turn would reimburse *A* for *B*'s $\frac{2}{7}$ share of the costs and would distribute those costs to the appropriate fixed asset and expense and other accounts in his (*B*'s) own accounting records.

¹² See, e.g., I. T. 3930, 1948-2 Cum. Bull. 126.

be so classified, any income of the joint venture would be subject to the corporate income tax and in turn distributions from earnings and profits of the joint venture would be taxable as dividend income to the participants.¹³

According to interpretations issued by the Internal Revenue Service, an association in the oil and gas industry will be taxed as a corporation if *all* four of the following characteristics are found to exist:

1. There must be associates.
2. There must be a continuity of existence.
3. Control of the venture operations must be centralized.
4. The venture must have a joint profit objective.¹⁴

Since the first three characteristics are generally found in the oil and gas organization, one must avoid the profit objective to escape corporate classification. This objective can be avoided if each participant reserves the right to take the oil or gas produced from the property in kind. A joint profit objective will not result if the participants grant authority to one person to market the production, but such authority *must* be revocable at the will of the participants. Furthermore, the authority must be limited so that the person empowered to market the production is not permitted to enter into any sales contract for a period longer than is required by the minimum needs of the industry and in no event for a period longer than one year.¹⁵

For purposes of illustration assume the following facts: *A*, an oil operator, has a mineral lease which cost him 5,000 dollars on a tract of land whereby he is the owner of the full $\frac{7}{8}$ working interest, and has accumulated substantial evidence that the property has a bright promise of production. He is not in a position to undertake development of the property without financial backing. *B*, an investor, is willing to finance the drilling of a well on the property in return for a sixty per cent interest in the property. Assume that the cost of such well aggregates 100,000 dollars for intangibles and 25,000 dollars for tangible equipment. There are various alternative considerations:

Drilling for an interest under a simple joint venture

The simplest form of joint venture would provide that a sixty per cent interest would be assigned to *B* in consideration of his bearing the entire cost of the first well. Such a joint venture would

¹³ 10 Oil & Gas Tax Q. 177 (1961).

¹⁴ I.T. 3930, *supra* note 12.

¹⁵ I.T. 3948, 1949-1 Cum. Bull. 161.

also be likely to provide that in the event the well was a producer, *B* would be entitled from the outset to sixty per cent of $\frac{7}{8}$ (being the full working interest) of the oil or gas produced and that *A* would be entitled from the outset to forty per cent of the oil or gas applicable to the working interest. It would further provide that operating costs and future development costs would be borne sixty per cent by *B* and forty per cent by *A*.

B would be required for income tax purposes to capitalize as leasehold cost forty per cent of the cost of the well. He could claim as a current deduction from his taxable income sixty per cent of the intangible drilling and development cost (assuming a proper election is in effect) and would capitalize and could expect to recoup through depreciation deductions over the life of the property sixty per cent of the cost of the tangible equipment.

In the foregoing circumstances, if the well is dry and the lease is abandoned, *B* would realize a tax benefit from the forty per cent capitalized as leasehold cost through a deduction of such costs as a worthless lease in the year of abandonment.¹⁶ However, if the well is more than a mild success, the amount required to be capitalized as leasehold cost might result in no effective tax benefit to *B* because of the availability of percentage depletion which in most instances would exceed cost depletion. The well cost would be distributed in *B*'s records as follows:

Leasehold cost (40% of \$125,000)	\$ 50,000
Intangible drilling and development costs	60,000
Lease and well equipment	15,000
	<hr/>
	\$ 125,000

If the well is a producer, *A*'s accounting is affected only by the fact that a formerly nonproducing property has become productive. He should make an entry transferring his basis of 5,000 dollars from nonproducing to producing leaseholds. The detail producing leasehold records should clearly describe the nature of his interest, *i.e.*, forty per cent of $\frac{7}{8}$. He would not be entitled to deduct any part of the intangible drilling and development costs on the first well and would not have a basis in any part of the equipment cost applicable to such well inasmuch as he did not bear any portion of such costs.

Assignment of a full working interest with reversionary rights to assignor

A may be willing to assign to *B* the full working interest with the understanding that forty per cent of the working interest will

¹⁶ Treas. Reg. § 1.165-2 (1960).

revert to *A* after *B* has recouped from production, *i.e.*, revenues less operating costs, the full cost of the well. This type of arrangement is referred to as a carried interest, *i.e.*, *B* is carrying *A* for the cost of the well.

Generally, under Internal Revenue Service procedures, *B* would be entitled to a full deduction for all intangible drilling and development costs because he owned the full working interest at the time the well was drilled and continued to own such interest during the "complete payout period"¹⁷ of the well. Furthermore, the full cost of his tangible equipment becomes cost subject to depreciation.¹⁸ The transaction would be recorded for accounting purposes as follows:

Debit—Lease and well equipment	\$ 25,000	
Intangible drilling and development costs	100,000	
Credit—Cash		\$ 125,000

The gross revenues during the period of payout would be ordinary income to *B* subject to depletion. Assume that at the time of payout, accumulated depreciation on the equipment is 10,000 dollars and unrecovered cost 15,000 dollars. In the reassignment to *A*, *B* will relinquish forty per cent of his interest in the equipment; therefore, some disposition must be made of forty per cent of the unrecovered cost and, depending on the length of the payout period, *B* may be required to add to his tax, for the year of disposition, a portion of the investment credit previously taken.¹⁹ The Service holds that the portion of the unrecovered cost attributable to the interest relinquished must be added to depletable leasehold cost by the assignor.²⁰ *B*'s entry to record the reassignment would then be as follows:

Debit—Producing leasehold	\$ 6,000	
Reserve for depreciation— Leasehold equipment (40% of \$10,000)	4,000	
Credit—Leasehold equipment (40% of \$25,000)		\$ 10,000

¹⁷ *Manahan Oil Co.*, 8 T.C. 1159 (1947).

¹⁸ *Manahan Oil Co.*, 8 T.C. 1159 (1947).

¹⁹ Int. Rev. Code of 1954, § 47. In addition, the Service may contend that there has also been a depreciation recapture under § 1245, if *B* is deemed to have made a disposition of tangible property.

²⁰ The use of an accelerated method of depreciation, such as the declining balance, the sum-of-the-years digits, or the unit-of-production (assuming flush production in the early years) methods would result in a smaller cost to be added to leasehold cost at the time of payout.

Assuming that percentage depletion exceeds the amount of cost depletion applicable to the property, *B* will not obtain any tax benefit from the 6,000 dollars in unrecovered equipment cost assigned to leasehold cost. *B* might prevail in the courts against the practice of the Internal Revenue Service in this regard, on the basis of a Supreme Court decision which held that a taxpayer could not be forced to look to depletion from a wasting asset to recoup investment in depreciable equipment.²¹

A's accounting is affected only by the fact that a formerly nonproducing property has become productive. On the original assignment, the basis in the original property becomes the basis of his "carried interest" or reversionary rights after payout. He should make an entry transferring his basis from nonproducing to producing leasehold. The detail producing leasehold records should clearly describe the nature of his interest. On reassignment after payout, his accounting is not affected; however, he should amend the detail leasehold cost records to describe the reassignment resulting from completion of the obligation under his reversionary rights.

Assignment of part working interest and an oil payment out of the retained working interest

Another solution is for *A* to assign to *B*, after completion of the development obligation by *B*, sixty per cent of the working interest and an oil payment, payable out of one-half of his retained working interest, equal to his share of the cost of the well drilled. Using the amounts in the foregoing example, the oil payment would amount to forty per cent of 125,000 dollars or 50,000 dollars.

Because *B* received only sixty per cent of the working interest in the assignment from *A*, he is entitled to deduct only sixty per cent of the intangible costs incurred and to capitalize as cost subject to depreciation only sixty per cent of the equipment. Of his total costs forty per cent must be assigned as cost of the oil payment.²² The well cost would be distributed in *B*'s records as follows:

Producing oil payment interest (40% of \$125,000)	\$ 50,000
Intangible drilling and development costs (60% of \$100,000)	60,000
Lease and well equipment (60% of \$25,000)	15,000
	<u>\$ 125,000</u>

²¹ Choate v. Commissioner, 324 U.S. 1 (1945).

²² Herndon Drilling Co., 6 T.C. 628 (1946). The Service has acquiesced on the deductibility of the intangibles. 1946-2 Cum. Bull. 3.

Since the oil payment cost would exactly equal the oil payment income, *B* would realize *no* taxable income from the payout of the oil payment.

Assuming the well is productive, *A*'s accounting is affected only in that a formerly nonproducing property has become productive. On the assignment, the basis in the original property becomes the basis in his retained working interest subject to an oil payment. He should make an entry transferring his basis from nonproducing to producing leaseholds. The detail producing leasehold records should clearly describe the nature of his interest. After the oil payment has been satisfied, he should so indicate in the detail cost records.

Partial assignment and lien on retained interest

As an alternative solution, after completion of the development obligation by *B*, *A* would assign to *B* sixty per cent of the working interest and grant to him a lien on the retained working interest to secure the development advances made for his benefit by *B*. This is considered a loan repayable only from production from the property. Using the same amounts as in the two examples above, the loan would amount to forty per cent of 125,000 dollars or 50,000 dollars.

Because the Commissioner has announced his nonacquiescence in the *Abercrombie* decision,²³ both *A* and *B* might be required to treat the transaction as though the full working interest with reversionary rights had been assigned to *B*, as discussed previously. However, even assuming *Abercrombie* applied, since *B* received only sixty per cent of the working interest in the assignment from *A*, he is entitled to deduct only sixty per cent of the intangible costs incurred and only sixty per cent of the equipment cost is subject to depreciation. Of his total costs, forty per cent or 50,000 dollars must be set up as an account receivable from *A*. The well cost would be distributed as follows:

Accounts receivable (40% of \$125,000)	\$ 50,000
Lease and well equipment (60% of \$25,000)	15,000
Intangible drilling and development costs (60% of \$100,000)	60,000
	<u>\$ 125,000</u>

²³ J. S. Abercrombie Co., 7 T.C. 120 (1946). The Service nonacquiesced in 1946-2 Cum. Bull. 6. In 1949-1 Cum. Bull. 1, the Service changed its position and acquiesced. This acquiescence was withdrawn in 1963-2 Cum. Bull. 6, restoring non-acquiescence.

Forty per cent of the production from the property would apply to reduce the account receivable. If production from the property is insufficient to recover the total receivable, *B* would be entitled to a bad debt deduction at the time of abandonment of the property. On the basis of the *Abercrombie* decision, because *A* did not make an assignment of his forty per cent interest in the property to *B*, he retains his interest subject only to a lien. He is, therefore, entitled (1) to deduct his share of the intangible drilling and development costs, and (2) to capitalize his share of the equipment costs subject to recovery through depreciation. These costs should be offset by a liability to *B* which is to be satisfied out of *A*'s share of the production. *A*'s entry to record the advances by *B* on his behalf is summarized as follows:

Debit—Leasehold equipment (40% of \$25,000)	\$ 10,000	
Intangible drilling and de- velopment costs (40% of \$100,000)	40,000	
Credit—Accounts payable		\$ 50,000

Appropriate detail records should, of course, be posted.²⁴

Forty per cent of the production would apply to reduce the account payable. If production from the property is insufficient to satisfy the total payable, *A* would recognize ordinary income to the extent of the unpaid liability. *A*'s share of the production applied to satisfy the liability would be ordinary income subject to depletion.²⁵

²⁴ Presumably, following the rationale of the *Abercrombie* decision, *A* would be entitled to an investment credit with respect to his 40% share of leasehold equipment.

²⁵ Inasmuch as each participant in a co-ownership arrangement has an undivided interest in the properties and in each operating transaction, it is necessary that the operator report each property and operating transaction to the participants periodically. This report, commonly referred to as a joint venture billing, serves as the basis for billing each participant for his share of the costs of developing and operating the property and also provides the basis whereby each participant may record his share of the costs in accordance with his own elections as to the handling of items for income tax purposes. Income may also be distributed to the participants by the operator. However, quite often each participant is paid directly for his share of production by the purchaser, thus eliminating an accounting to the participants by the operator of the property.

To prepare the joint venture billing, the operator of the property must refer to the pertinent provisions of the operating agreement. The most important accounting provisions of the agreement deal with the allocation of costs and revenues among the participants. These are usually allocated in the ratio of each owner's interest in the property. Other important provisions of the agreement deal with the allocation of costs to the property. Most costs, such as drilling and direct lifting, are chargeable

PARTNERSHIP ARRANGEMENTS

Like co-ownership arrangements, partnerships are contractual among the participants. Unlike the co-ownership arrangement, however, the partnership is a tax reporting entity.²⁶ The entity makes its own elections as to the handling of all items for tax purposes except as to foreign tax credits.²⁷ For example, the partnership entity must make the election either to expense or to capitalize intangibles. The election may not be made independently by each participant as to properties employed by the partnership.

As previously pointed out, the participants in an oil venture may avoid the classification of a partnership (an entity concept). However, in some cases, the partnership provisions of the Internal Revenue Code may be used to advantage.

Assume the same facts as described in the foregoing section on co-ownership arrangements, regarding the proposed association of *A*, an oil operator and *B*, an investor. *B* is willing to finance the drilling of a well on a property (now owned by *A*) provided that he can get an income tax deduction for the cost of the intangible drilling and development costs incurred and a sixty per cent interest in the well. If the venture proves to be successful, he wishes to be reimbursed for *A*'s forty per cent interest in the well, and is willing to obtain reimbursement from *A*'s forty per cent of production. *A* may assign the full working interest to *B*, retaining reversionary rights to forty per cent of the working interest after forty per cent of the development costs have been recovered by *B* (out of production from forty per cent of the working interest). *A* and *B* may also solve this problem by entering into a partnership. For income tax purposes, a partner's distributive share of income and deductions is to be determined by the provisions of the partnership agreement,²⁸ thus a partnership agreement may be drawn to provide that *B* be allocated all of the deductions for intangibles and depreciation on the first well, and all of the income and related depletion from the property until such time as he is reimbursed for his investment. Following is a comparative summary (over the period of

directly to the property when incurred. However, costs of such items as supervision are more difficult to allocate equitably among the properties under the control of the operator. Therefore, most operating agreements provide for fixed monthly rates for costs that are difficult to charge directly. The rates are usually set on a "per drilling well" or a "per producing well" basis. Rates may also be set in the contract for use of the operator's equipment. Price protection clauses may also be included for materials used out of the operator's stock.

²⁶ Int. Rev. Code of 1954, § 6031.

²⁷ Int. Rev. Code of 1954, § 703(b).

²⁸ Int. Rev. Code of 1954, § 704(a).

payout of the advances) of the tax consequences to *B* of the above described co-ownership solution and the partnership solution to the problem:

	Co-ownership Arrangement	Partnership
Taxable income		
Reduced by intangibles	\$ 100,000	\$ 100,000
Reduced by depreciation of equipment	19,000	25,000
Increased by production	(125,000)	(125,000)
Reduced by allowable de- pletion on income	34,375 (27½%)	34,375 (27½%)
	<u>\$ 28,375</u>	<u>\$ 34,375</u>

It is apparent that the partnership arrangement is most advantageous to *B* in the amount of 6,000 dollars and, in addition, avoids the loss of previously claimed investment credits. This advantage results from the fact that in the co-ownership arrangement a portion of the undepreciated cost at the time of payout has to be capitalized as leasehold cost.

Assume that the facts of the proposed association of *A* and *B* are changed in that *A* is unwilling to allow *B* to be reimbursed for the development costs of *A*'s forty per cent interest in the well. *B* may agree to this provision but may, on the other hand, insist that he be able to obtain an income tax deduction for *all* of the intangible development costs incurred and for *all* of the depreciation applicable to the intangibles on the first well. Because of the unwillingness of *A* to allow reimbursement to *B* for development costs, the assignment of the full working interest with reversionary rights will not be satisfactory. Neither will the simple form of sharing arrangement solve the problem, because under this arrangement *B* will be required to capitalize a portion of his development costs (that is, a portion of the costs equal to the portion of the working interest not obtained) as leasehold costs. *A* and *B* may draw their agreement to provide that all of the deductions for intangibles and depreciation on the first well will be allocated to *B* and that the income and related depletion from the property be allocated forty per cent to *A* and sixty per cent to *B*.

SYNDICATES

During recent years the participation of investors in drilling programs conducted by unincorporated syndicates has become increasingly popular. The syndicate has increased in popularity because of its convenience in allowing an investor to diversify his investment by acquiring a relatively small interest in a large number of prospects.

Under a typical syndicate plan, an annual fund is subscribed to by the participating investors. Each investor owns that proportion of each prospect developed during the year after deducting the interest to be acquired by the syndicate in exchange for its services, that his subscription bears to the total annual fund. Usually in exchange for its services the syndicate will retain a carried working interest in the initial or exploratory well of approximately twenty-five per cent in each prospect developed. In other words, each investor will pay his proportionate share of the costs of the exploratory well which are attributable to the carried interest and shall be entitled to recoup his share of such costs from the initial income from the well which is allocable to the carried interest. The syndicate does not realize any taxable income on this transaction nor is it entitled to any deductions for the costs applicable to the carried interest which are paid by the investors. On the other hand, for tax purposes the investors will be entitled to treat the costs applicable to the carried interest in accordance with their underlying nature (intangible development cost, tangible equipment, operating expense, etc.) and the investors would be required to report the income received during the payout period as ordinary income subject to depletion.²⁹

When the investors have recovered their costs in full the syndicate commences paying its share of current operating expenses and becomes entitled to receive its share of the income from the well. It should be noted that the carried interest arrangement is usually applicable to only the initial or exploratory well on a prospect. The syndicate pays its proportionate share of development and operating costs on all subsequent wells. If the exploratory well is successful then the development of the leases involved in the prospect is usually governed by the terms of a standard form of joint operating agreement generally employed in the petroleum industry.

The operating and development costs incurred by the syndicate are charged to the investors on the basis of actual cost. In

²⁹ I.T. 3930, 1948-2 Cum. Bull. 126. Generally in a large syndicate, the management will seek a ruling from the Internal Revenue Service that the syndicate will not be classified as an association taxable as a corporation.

addition the syndicate makes a small charge (usually from five to ten per cent of the money committed to the fund) in lieu of overhead and supervision charges.

In most instances the syndicate will act as operator of the properties developed and will furnish the investor with a periodic accounting for funds expended. In addition the typical syndicate usually furnishes the investor with various periodic reports.

To illustrate the type of information required for tax purposes which is furnished to investors by the typical syndicate, assume that *A* subscribes 10,000 dollars to the Texas Syndicate on January 1, 1964, and that the total fund is to be 500,000 dollars. *A* accordingly has a participation in the fund of two per cent of the total. The 500,000 dollars is expended during 1964 as follows:

	Leasehold cost	Dry holes	Producers	Total
White lease	\$ 10,000	\$ 80,000		\$ 90,000
Black lease	25,000		\$ 125,000	150,000
Green lease	15,000	105,000		120,000
Blue lease	25,000		115,000	140,000
	<hr/> \$ 75,000	<hr/> \$ 185,000	<hr/> \$ 240,000	<hr/> \$ 500,000

Moreover, assume that gross income received during 1964 totaled 40,000 dollars and operating expenses amounted to 6,000 dollars. The White lease and the Green lease were abandoned during 1964 after having been condemned by the dry holes drilled thereon. Also assume that it was found advantageous to make the election to exclude the syndicate from the partnership provisions of the Internal Revenue Code and that such election was timely made.

The following schedules are indicative of the type of information which might be furnished by the syndicate to each investor:

- Schedule I —Taxable income of participants
- Schedule II —Allowable depletion
- Schedule III—Depreciation

SCHEDULE I

TEXAS SYNDICATE TAXABLE INCOME OF PARTICIPANTS FOR YEAR ENDED DECEMBER 31, 1964

	Schedule reference	100%	<i>A</i> 's 2% interest
Gross income	II	<hr/> \$ 40,000.00	<hr/> \$ 800.00

Deductions:

Intangible develop- ment costs	II	144,000.00	2,880.00
Dry hole costs		185,000.00	3,700.00
Abandoned leaseholds		25,000.00	500.00
Operating expenses (including produc- tion taxes)	II	6,000.00	120.00
Depreciation	III	9,000.00	180.00
Depletion	II	1,475.00	29.50
		<u>370,475.00</u>	<u>7,409.50</u>
Loss to be reported on Schedule C, Form 1040		<u>\$ 330,475.00</u>	<u>\$ 6,609.50</u>

SCHEDULE II

TEXAS SYNDICATE
ALLOWABLE DEPLETION
FOR YEAR ENDED DECEMBER 31, 1964

	Black lease	Blue lease	Total
Gross income	<u>\$ 15,000</u>	<u>\$ 25,000</u>	<u>\$ 40,000</u>
Deductions:			
Operating expenses (in- cluding production taxes)	2,500	3,500	6,000
Intangible develop- ment costs	80,000	64,000	144,000
Depreciation (Schedule III)	4,900	4,100	9,000
	<u>87,400</u>	<u>71,600</u>	<u>159,000</u>
Net loss before depletion	<u>\$ 72,400</u>	<u>\$ 46,600</u>	<u>\$119,000</u>
Allowable depletion:			
(1) Percentage:			
27½% of gross income, limited to 50% of net income before depletion	None	None	None
(2) Cost:			
(A) Units sold	5,000	8,500	
(B) Total estimated re- coverable units	200,000	250,000	
(C) Ratio of (A) to (B)	2.5%	3.4%	
(D) Leasehold cost	\$ 25,000	\$ 25,000	
Depletion: (D) multi- plied by (C)	<u>\$ 625</u>	<u>\$ 850</u>	<u>\$ 1,475</u>

SCHEDULE III

TEXAS SYNDICATE
DEPRECIATION
FOR YEAR ENDED DECEMBER 31, 1964

<u>Description</u>	<u>Acquired</u>	<u>Cost</u>	<u>Estimated life</u>	<u>Method</u>	<u>Depreciation</u>
Black lease lease and well equipment	July 1, 1964	\$49,000	10 years	Declining balance	\$ 4,900
Blue lease lease and well equipment	July 1, 1964	41,000	10 years	Declining balance	4,100
					<u>\$ 9,000</u>

Note to Investor—

Depreciation has been computed above on the declining balance method. However, it should be noted that in the year of acquisition of a depreciable property, each investor has the right to select the allowable method of depreciation best suited to his needs. Furthermore, each investor may claim additional first year depreciation in his personal return to the extent allowed by section 179 of the Internal Revenue Code. Any changes made in the depreciation deduction claimed by the individual investor must be given effect in the computations on Schedules I and II.

Each investor should claim his proportionate share of the above property for investment credit purposes. All tangible equipment was purchased new in 1964.

DETERMINATION OF INCOME AND OPERATING EXPENSES

In order to determine his taxable income, the taxpayer must choose and consistently apply a method of accounting which will clearly reflect the income of his trade or business.³⁰ The principal methods of accounting from which he may choose are the cash basis and the accrual basis.

A taxpayer employing the cash basis of accounting includes in his gross income all income subject to tax received during the year in cash or its equivalent. His expenses include all disbursements made during the year in cash or its equivalent, to the extent that such disbursements are allowable as deductions. Both the cash basis and accrual basis taxpayer are required to capitalize expenditures for properties and fixed asset additions.

A taxpayer employing the accrual basis of accounting includes in his gross income all income earned even though not received in cash. The right to receive an item of income usually determines when it is earned. His expenses include all currently deductible

³⁰ Int. Rev. Code of 1954, § 446.

costs incurred during the taxable year. A cost is considered to be "incurred" at the time an actual liability is incurred. Generally, a cost is considered deductible unless it is attributable to property, such as inventory, prepaid items (such as insurance premiums covering more than one year) or property subject to depletion and depreciation, the useful life of which extends beyond the taxable year.

Depletable and nondepletable income distinguished

The operator or investor in the oil and gas production industry must determine which items of income are subject to depletion. The depletion allowance is determined by reference either to the cost or other basis of the mineral property (cost depletion) or to the income from the property (percentage depletion).³¹ Income from the property refers to the proceeds from the sale of the production from an oil and gas well.

Types of nondepletable income are not so easily distinguished. Gains from the sale of oil or gas properties are not depletable income.³² Income received from delay rentals is not depletable income. However, the receipt of a lease bonus by the lessor or sublessor of a mineral interest represents a payment in advance for oil and gas to be extracted and is considered ordinary income subject to depletion.³³

Depletable income is defined as the amount for which the taxpayer sells the oil and gas in the immediate vicinity of the well, *i.e.*, the field or market price before conversion or transportation.³⁴ Thus, if oil or gas is not sold in the immediate vicinity of the well or is not sold until after a conversion or a refining process, the income, thus determined, will have to be allocated for accounting purposes between (1) transportation, conversion, or refining, and (2) sale of oil and gas from the well.

Because depletion must be computed for *each* property or allowable combination of properties, it is essential that depletable income be determined for each such property or allowable combination of properties. Furthermore, in order to compute cost depletion, it is necessary to determine the number of mineral units (barrels of oil or MCF of gas) sold from the property during the taxable year. Thus, sales of oil and gas should be determined in terms of both money and quantities.

³¹ Int. Rev. Code of 1954, §§ 612, 613.

³² However, Int. Rev. Code of 1954, § 613(a), provides that for purposes of computing the 50% of taxable income limitation on percentage depletion, expenses of operating the property are required to be decreased for applicable depreciation recapture under § 1245.

³³ *Burnet v. Harmel*, 287 U.S. 103 (1932); G.C.M. 27322, 1952-2 Cum. Bull. 62.

³⁴ Treas. Reg. § 1.613-3(a) (1960).

CONCLUSION

It can readily be seen that the potential investor in oil and gas should select a business form suited to his peculiar needs. The individual in the high income bracket will be well advised to scrutinize the corporate form, particularly if he contemplates a broad-guage drilling activity. It will be significant to him that the corporate entity is taxed separately and that the corporate form is inherently efficient. The practitioner will want to compare the small business corporation under section 1371 with a joint venture arrangement, and both with a partnership. The tax impact is important, but not the only factor in selecting a vehicle for enterprise.

A suggested approach for the practitioner would be as follows: (1) determine the client's needs and desires as well as his resources and those of his associates; (2) ascertain the magnitude of his projected operation; (3) assess the impact of taxes and its corollary—expense allocation—upon the client.